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STUDY OF SCALE FORMATION DUE TO INCOMPATIBLE WATER

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Abstract. In the oil field, due to the extensive use of water injection for oil displacement and pressure maintenance, many reservoirs experience the problem of scale deposition when injection water begins to break through. Experience in the oil industry has indicated that many oil wells have suffered flow restriction because of scale deposition within the oil producing formation matrix and the down-hole equipment, generally in primary, secondary and tertiary oil recovery operation as well as scale deposits in the surface production equipment. This study was conducted to investigate the permeability reduction caused by deposition of calcium, strontium, and barium sulfates in sandstone cores from mixing of injected sea water and formation water that contained high concentration of calcium, barium, and strontium ions at various temperatures (50 - 80 °C) and differential pressures (100 - 200 psig). The solubility of common oil field scales formed and how their solubilities were affected by changes in salinity and temperatures (40 - 90 °C) were also studied. The morphology and particle size of scaling crystals formed as shown by Scanning Electron Microscopy (SEM) were also presented. The results showed that a large extent of permeability damage caused by calcium, strontium, and barium sulfates that deposited on the rock pore surface. The rock permeability decline indicates the influence of the concentration of calcium, barium, and strontium ions. At higher temperatures, the deposition of $CaSO_4$, and $SrSO_4$ scales increases and the deposition of $BaSO_4$ scale decreases since the solubilities of $CaSO_4$, and $SrSO_4$ scales decreases and the solubility of $BaSO_4$ increases with increasing temperature. The deposition of $CaSO_4$, $SrSO_4$, and $BaSO_4$ scales during flow of injection waters into porous media was shown by Scanning Electron Microscopy (SEM) micrographs.

Keywords: Scale deposition; scale solubility; scale concentration; temperature; pressure effects

1.0 INTRODUCTION

Secondary recovery is one of the activities used to improve oil recovery. There is several method used in secondary recovery. For example, water and gas flooding. The injection of water or gas into the oil-bearing reservoir is to increase the recovery factor and to maintain the reservoir pressure. In water flooding, the injected water will react with both the water already in the pore space of the rock (formation water) and with the mineral in the rock itself. This reaction will create scale formation.

Precipitation of mineral scales causes many problems in oil and gas production operations such as formation damage, production losses, increased workovers in

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producers and injectors, poor injection water quality, and equipment failures due to under-deposit corrosion. The most common mineral scales are sulfate and carbonate-based minerals. However, scale problems are not limited to these minerals and there have recently been reports of unusual scale types such as zinc and lead sulfides [1].

The objective of this work was to investigate permeability reduction by deposition of common oil field scales in porous media at various temperatures and concentrations and knowledge of solubility of common oil field scales formed and how their solubilities were affected by changes in salinity and temperature.

1.1 Scale Deposition Mechanisms

Scale deposition is one of the most serious oil field problems that inflict water injection systems primarily when two incompatible waters are involved. Scale deposition can occur from one type of water because of super-saturation with scale-forming salts attributable to changes in the physical conditions under which the water exists. Scale also deposited in down-hole pumps, tubing, casing flow-lines, heater treaters, tanks and other production equipment and facilities. Scale can occur near the downstream of any point in the production system where super-saturation is generated. Super-saturation can be generated in water by changing the pressure and temperature conditions or by mixing two incompatible waters. The most common oil field scales deposited are calcium carbonate, calcium sulfate, strontium sulfate and barium sulfate. Scale also can deposit when two incompatible waters are mixed and super-saturation is reached [2 - 7].

1.2 Source of Oil Field Scale

The chief source of oil field scale is mixing of incompatible waters. Two waters are called incompatible if they interact chemically and precipitate minerals when mixed. A typical example of incompatible waters are sea water with high concentration of SO_4^{-2} and low concentrations of Ca^{+2}, Ba^{+2}/Sr^{+2}, and formation waters with very low concentrations of SO_4^{-2} but high concentrations of Ca^{+2}, Ba^{+2} and Sr^{+2}. Mixing of these waters, therefore, causes precipitation of $CaSO_4$, $BaSO_4$, and/or $SrSO_4$. Field produced water (disposal water) can also be incompatible with seawater. In cases where disposal water is mixed with seawater for re-injection, scale deposition is possible [8 - 12].

1.3 Oil Field Scale Types

The most common oilfield scales are listed in Table 1, along with the primary variables that affect their solubility [13]. These scales are sulfates such as calcium sulfate (anhydrite, gypsum), barium sulfate (barite), and strontium sulfate (celestite) and

Table 1 Most common oil field scales

Name	Chemical Formula	Primary Variables
Calcium Carbonate dissolved	$CaCO_3$	Partial pressure of CO_2, temperature, total salts, pH
Calcium Sulfate:		
Gypsum	$CaSO_4.2H_2O$	
Hemihydrate	$CaSO_4.H_2O$	Temperature, total dissolved salts, pressure
Anhydrite	$CaSO_4$	
Barium Sulfate	$BaSO_4$	Temperature, pressure
Strontium Sulfate	$SrSO_4$	Temperature, pressure, total dissolved salts
Iron Compounds:		
Ferrous Carbonate	$FeCO_3$	
Ferrous Sulfide	FeS	Corrosion, dissolved gases, pH
Ferrous Hydroxide	$Fe(OH)_2$	
Ferrous Hydroxide	$Fe(OH)_3$	

calcium carbonate. Other less common scales have also been reported such as iron oxides, iron sulfides and iron carbonate.

1.4 Scale Formation along the Injection-Water Path in Water-Flood Operations

At the injection wellhead, injection water temperature is usually much lower than reservoir temperature. When it travels down the injection well-string, the water cools the surrounding formations, and its temperature and pressure increase. If the water is saturated at surface conditions with salts whose solubility decreases with increasing temperatures (e.g. anhydrite), scale may form along the well-string.

Scale precipitation from the injection water may happen behind the mixing zone as a consequence of temperature and pressure changes. This is particularly true of waters containing salts whose solubility decreases with increasing temperature and decreasing pressure. Forward of the mixing zone only reservoir brine (with oil) is present in the rock pores. Behind the mixing zone, only injected water in equilibrium at local temperature and pressure (with residual oil) exists. In the mixing zone, precipitation of insoluble salts may occur due to the interaction, at local temperature and pressure, of chemical species contained in the injection water with chemical species present in the reservoir brine.

Nevertheless, at a different pressure, the remaining clear water moves ahead mix again with reservoir brine and scale precipitation may again take place. This cycle is repeated until the remaining clear water reaches a production well. Pressure and temperature decrease along the flow string up to the surface in the production well,

and further changes in thermodynamic conditions occur in the surface equipment. This may again result in scale formation. Normally, these scales do the most damage in the well-bore when there are major falls in pressure but hardly any temperature changes [14].

There are three principal mechanisms by which scales form in both offshore and onshore oil field system [15, 16]:

(i) Decrease in pressure and/or increase in temperature of a brine, goes to a reduction in the solubility of the salt (most commonly these lead to precipitation of carbonate scales, such as $CaCO_3$).

$$Ca(HCO_3)_2 \Leftrightarrow CaCO_3 + CO_2 + H_2O \quad (1)$$

(ii) Mixing of two incompatible brines (most commonly formation water rich in cations such as barium, calcium and/or strontium, mixing with sulfate rich seawater, goes to the precipitation of sulfate scales, such as $BaSO_4$).

$$Ba^{2+}\left(\text{or } Sr^{2+} \text{or } Ca^{2+}\right) + SO_4^{2-} \Leftrightarrow BaSO_4\left(\text{or } SrSO_4 \text{or } CaSO_4\right) \quad (2)$$

Other fluid incompatibilities include sulfide scale where hydrogen sulfide gas mixes with iron, zinc or lead rich formation waters:

$$Zn^{2+} + H_2S \Leftrightarrow ZnS + 2H^{2+} \quad (3)$$

(iii) Brine evaporation, resulting in salt concentration increasing above the solubility limit and goes to salt precipitation (as may occur in HP/HT gas wells where a dry gas stream may mix with a low rate brine stream resulting in dehydration and most commonly the precipitation of NaCl).

1.6 The Scaling Problem in Oil Fields

A scale problem will occur, if at a high water cut part of the water is present as free water. The rate of scale deposition will then be approximately pro-portional to the rate of free water production. Depending upon where the formation water becomes supersaturated, scale may be deposited in the flow line only, in both flow line and tubing, and in some cases even in the perforations and in the formation near the wellbore.

Oil field scales costs are high due to intense oil and gas production decline, frequently pulling of down-hole equipment for replacement, re-perforation of the producing intervals, re-drilling of plugged oil wells, stimulation of plugged oil-bearing formations, and other remedial workovers through production and injection wells. As scale deposits around the well-bore, the porous media of formation becomes plugged and may be rendered impermeable to any fluids.

The production problems caused by mineral scale in oil production operations have long been known. Among the most onerous of all scaling problems is that of

sulfate scales, particularly barium sulfate scale. This is a difficult scaling problem because of the low solubility of barium sulfate in most fluids and the commensurate low reactivity of most acids with barium sulfate scale.

Many case histories of oil well scaling by calcium carbonate, calcium sulfate, strontium sulfate and barium sulfate have been reported [17 - 20]. Problems in connection to oil well scaling in the Russia where scale has seriously plugged wells and are similar to cases in North Sea fields have been reported [17]. Oil fields scale problems have occurred because of water flooding in Saudi oil fields, Algeria, Indonesia in south Sumatra oil fields, and Egypt in el-Morgan oil field where calcium and strontium sulfate scales have been found in surface and subsurface production equipment [21].

1.7 Solubility of Scale Formation

Solubility is defined as the limiting amount of solute that can dissolve in a solvent under a given set of physical conditions. The chemical properties of interest to us are present in aqueous solutions as ions. Certain combinations of these ions lead to compounds which have low solubility. Once the solubility capacity is exceeded the compounds precipitate from solution as solids. Therefore, precipitation of solid materials, which may form scale, will occur if:

(i) The water contains ions which are capable of forming compounds of limited solubility.
(ii) There are changes in the physical conditions or water compositions which are lowering the solubility.

A solution that contains less solute than required for saturation is called an unsaturated solution. A solution, whose concentration is higher than that of a saturated solution due to any reason, such as change in other species concentration, temperature, etc., is said to be supersaturated. When the temperature or concentration of a solvent is increased, the solubility may increase, decrease, or remain constant depending on the nature of the system. For example, if the dissolution process is exothermic, the solubility decreases with increased temperature; if endothermic, the solubility increases with temperature.

2.0 MATERIALS AND METHODS

The general purpose of the laboratory test was to investigate permeability reduction by deposition of calcium, strontium, and barium sulfates in a porous medium and knowledge of solubility of calcium, strontium and barium sulfates and how their solubility are affected by changes in salinity and temperature.

2.1 Core Material

The rock cores used in the testes were sandstone from Malaysia with 3 inch length and of diameter 1inch with average porosity of 32% and of absolute permeability varied from 12.32 - 13.87 md. No oil was present in the cores. All the cores were cleaned using methanol in Soxhlet extractor and dried in a Memmert Universal Oven at 100 °C for overnight before use.

2.2 Brines

The ionic compositions of synthetic formation water and water injection (Angsi and Barton seawaters) are given in Table 2. Note the formation water has calcium, strontium, and barium ions, and the sea water contains sulfate ions. It is clear that the mixing of these waters can lead to calcium, strontium and barium sulfates precipitation.

Table 2 Ions of synthetic formation and injection waters

Ionic	Normal salinity formation water (ppm)	High salinity formation water (ppm)	Normal barium formation water (ppm)	High barium formation water (ppm)	Angsi seawater (ppm)	Barton seawater (ppm)
Sodium	52,132	52,132	42,707	42,707	10,804	9,749
Potassium	1,967	1,967	1,972	1,972	375	340
Magnesium	4,260	4,260	102	102	1,295	1,060
Calcium	7,000	30,000	780	780	429	384
Strontium	500	1,100	370	370	6.60	5.4
Barium	10	10	250	2,200	-	<0.2
Chloride	99,653	146,385	66,706	67,713	19,307	17,218
Sulfate	108	108	5	5	2,750	2,960
Bicarbonate	350	350	2,140	2,140	159	136

2.3 Scaling Test Rig

Experiments were carried out using a test rig, which is schematically shown in Figure 1. The core test equipment consists of five parts: constant pressure pump, transfer cell, oven, pressure transducer and core holder. There follows a brief description of each part.

Constant pressure pump: Double-piston plunger pump manufactured by Lushyong Machiney Industry Limited, with 1.5 horse power motor, maximum design pressure of 35 bars and approximate flow rate of 20 L/min was used to inject the brines during flooding at different pressures.

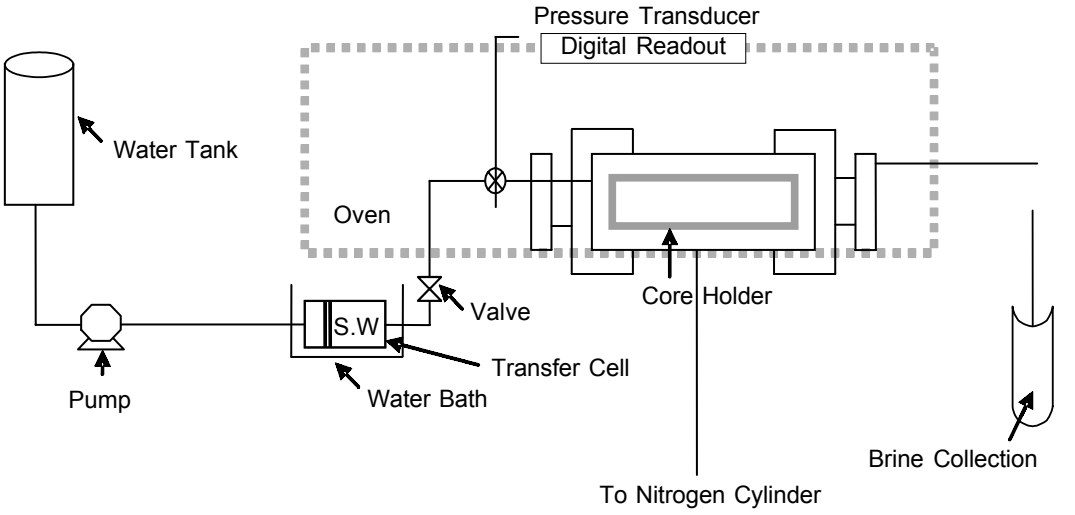

Figure 1 Schematic of the core flooding apparatus

Transfer cell: Stainless steel transfer cell manufactured by TEMCO, Inc., USA which can withstand pressures up to 10,000 psia was used to store and pump the injected brine to the core holder. The cell with a capacity of 1000 ml has a free-floating piston, which separates the pump fluid (distilled water) from the injection brine. The pump fluid was pumped into a transfer cell to displace the brine into the core.

Oven: During all flooding runs, the core holder is placed inside a temperature controlled oven.

Pressure transducer: The differential pressure across the core during flooding runs was measured by using a pressure transducer (model E-913 033-B29) manufactured by Lushyong Machiney Industry Limited, with a digital display.

Core holder: A Hassler type, stainless steel core holder designed for consolidated core samples, 3 inch length and 1 inch diameter, was used. The holder was manufactured by TEMCO, Inc., USA and could withstand pressures up to 10,000 psia. A rubber sleeved core holder, subjected to an external confining pressure, into which a sandstone core is placed.

2.4 Test Procedures

2.4.1 Beaker Test

For each experiment of common oil field scales, 100 mL of each filtered opposite waters were poured simultaneously into a beaker. The synthetic brines were heated on hot plate and the solution was stirred by magnetic stirrer and after that the solution was filtered through 0.45-μm filter paper. After filtration, 5 ml of the filt-rate was

taken into a 50 ml volumet-ric flask and was diluted with distilled water to make up to 50 ml of solution. This instantaneous dilution of $CaSO_4$, $SrSO_4$, and $BaSO_4$ containing brines was performed in order to prevent $CaSO_4$, $SrSO_4$, and $BaSO_4$ precipitation between filtering and analytical determination of the Ca, Sr, and Ba concen-trations. The Calcium, strontium, and barium determinations were calibrated by measuring five standard solutions. Standard solu-tions were prepared from $CaCl_2$, $SrCl_2$, and $BaCl_2$ solution. Calcium, strontium, and barium concentrations in the diluted filtrates were determined by atomic absorption spectrometry. After multiplying with the dilution factor, the exact concentrations of calcium, barium, and strontium were computed.

2.4.2 Core Test

Before each run, the core sample was dried in a Memmert Universal Oven at 100 °C for overnight. The core sample was prepared for installation in the core-holder.

A vacuum was drawn on the core sample for several hours to remove all air from the core. The core was saturated with formation water at room temperature, and a base permeability determined. After the appearance of formation water at the outlet flooding was continued long enough to ensure 100% saturation. The core holder assembly placed inside the oven and transfer cell containing sea water was then placed inside the water bath and heated to the desired temperature of the run. The required confining pressure was then adjusted to be approximately at double inlet pressure. A flooding run was started by setting plunger pump at different pressures. Thus, the sea water was injected into the core and mixed with formation water inside porous media. The inlet pressure was measured by pressure transducer while the outlet pressure was atmospheric pressure. During each run, the flow rate across the core was recorded continuously and the permeability of core was calculated with Darcy's linear flow equation before and after scale deposition. scale deposition have been observed, the core sample was removed at the end of flooding then dried and cut into sections for scanning electron microscopy (SEM).

3.0 RESULTS AND DISCUSSION

3.1 Beaker Test

The calcium, strontium, and barium concentrations in the diluted filtrates were determined by atomic absorption spectrometry. The solubility of $CaSO_4$, $SrSO_4$, and $BaSO_4$ at various temperatures of this study were calculated. Graphical presentations are given in Figures 2 to 4.

The expected trend in this temperature range is a decrease in $CaSO_4$ and $SrSO_4$ solubilities, because the dissociation of $CaSO_4$ and $SrSO_4$ is exothermic reaction. But this phenomenal was different for the $BaSO_4$. The solubility of $BaSO_4$ increases

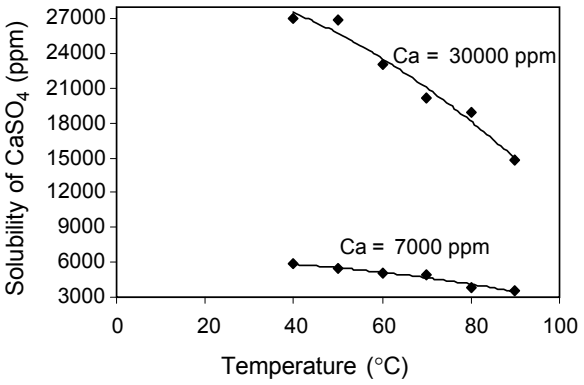

Figure 2 $CaSO_4$ solubility *vs.* temperature

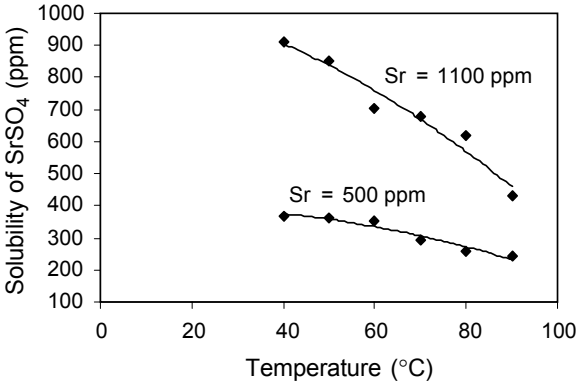

Figure 3 $SrSO_4$ solubility *vs.* temperature

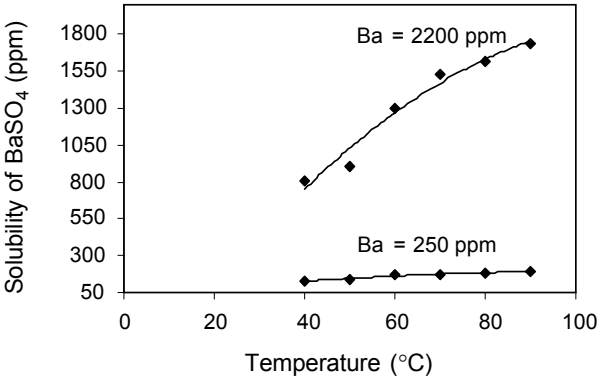

Figure 4 $BaSO_4$ solubility *vs.* temperature

with the increase of temperature due to its endothermic reaction. A graphical presentation of the experimental results is shown in Figures 2 to 4. The sulfate ion content in the sea water brine reacts with the barium ions in the formation water instantaneously but it reacts with both calcium and strontium ions only with heating. The more precipitation of $CaSO_4$, $SrSO_4$, and $BaSO_4$ results from the presence of a large concentration of calcium, strontium, and barium ions as compare to less precipitation at normal concentrations of calcium, strontium, and barium ions.

The experimental results confirm the general trend of solubility dependency for common oil field scales on temperature which is obvious and is similar to that observed in the earlier work [13, 18].

3.2 Core Test

The main objective of this part of the investigation is to study permeability reduction caused by common oil field scales deposition in porous media. The coreflood experiments were designed to investigate the effect of temperature (50 - 80 °C), differential pressure (100 - 200 psig), and different concentrations of calcium, strontium, and barium ions on the scaling tendency of brines (see Table 2).

During each run, the flow rate across the core was recorded continuously and the permeability of core was calculated using Darcy's linear flow equation. The flow rate decreased during the experiments only when a super-saturated solution was flowing through the cores. This confirms that the decrease of flow rate is due to precipitation of the calcium, strontium, and barium sulfates inside the core with the consequent reduction in its permeability and porosity. In the following, extend of permeability damage, decline trend of permeability ratio and the results for various temperatures, concentrations and differential pressure are discussed:

3.2.1 Extend of Permeability Damage

Extend of permeability loss caused by $CaSO_4$, $SrSO_4$, and $BaSO_4$ scaling in the rock pores varied in different situations. Figure 5 shows the permeability change of a less damaged core at a differential pressure 100 psig and 50°C (Figure 5a) and 80 °C (Figure 5b). Figure 6 shows that of a severely damaged core after $CaSO_4$, $SrSO_4$, and $BaSO_4$ scaling a differential pressure of 200 psig and 50 °C (Figure 6a) and 80 °C (Figure 6b). About 4%-14% and 5%-12% permeability loss was observed in Figure 5, but more than 15%-23% and 9%-19% initial permeability reduction could occur in a heavily scaled core, as shown in Figure 6. The reduction in permeability is possibly caused by crystals blocking the pore throats as shown later in the SEM view (Figures 13 and 14). The amount of precipitation varied within the sandstone cores, there being more scale near the formation water inlets and least scale was observed furthest from the inlet parts.

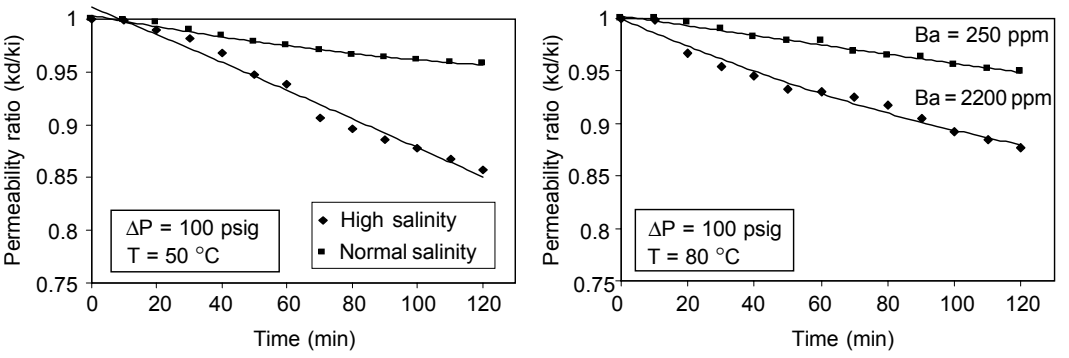

Figure 5 Variation of permeability ratio *vs*. time at various concentrations (a) 50 °C and (b) 80 °C and 100 psig

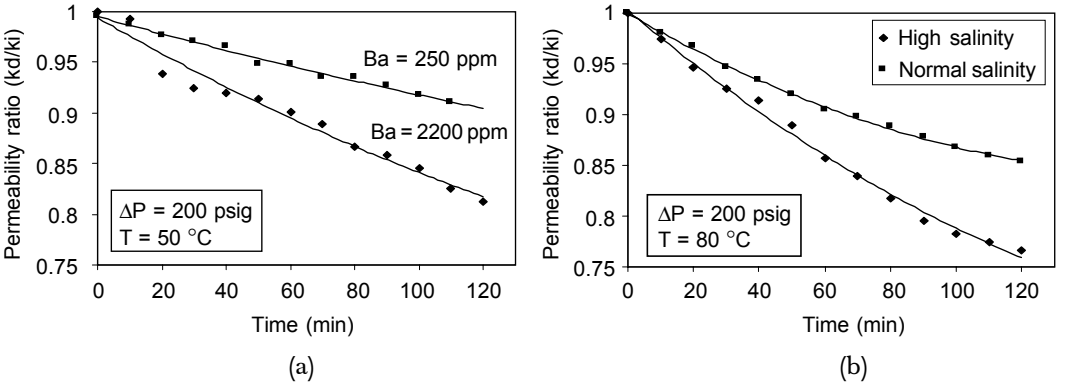

Figure 6 Variation of permeability ratio *vs*. time at various concentrations (a) 50 °C and (b) 80 °C and 200 psig

3.2.2 Decline Trend of Permeability Ratio

Figures (7 - 10) show the permeability decline trend changes with brine-injection time. During the initial flow period, the permeability declined sharply soon after the two waters mixed in the pores. The permeability decline then slowed and gradually leveled out after the permeability decreased greatly. This phenomenon was observed in all the core tests in which the scaling damage was severe.

3.2.3 Effect of Temperature

Temperature has a significant influence on solubility and crystal growth of calcium, strontium, and barium sulfates. To study its effect on the permeability reduction, a number of tests were carried out where concentration of injected brine was kept constant at differential pressure from 100 to 200 psig and temperatures of 50 and

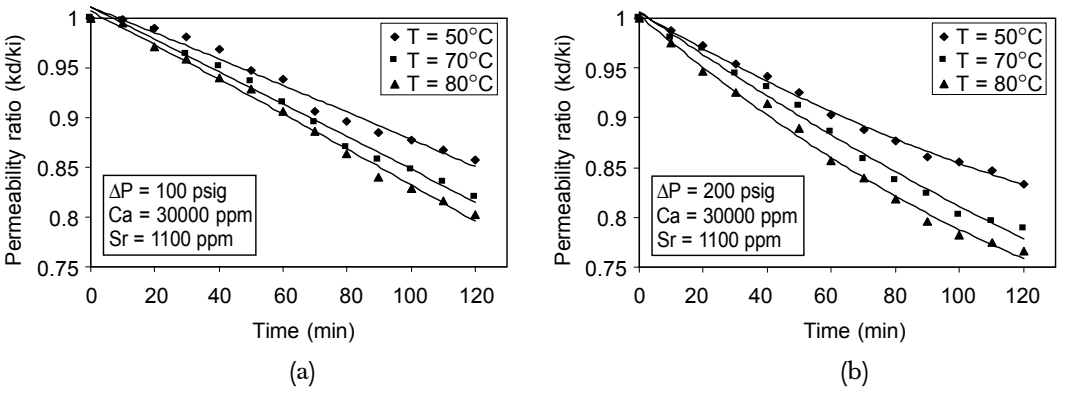

Figure 7 Variation of permeability ratio vs. time at various temperatures (a) 100 psig and (b) 200 psig

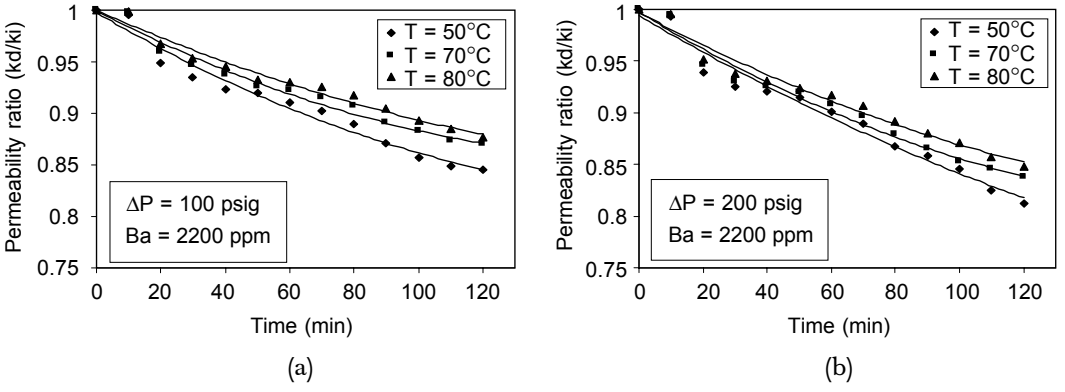

Figure 8 Variation of permeability ratio *vs.* time at various temperatures (a) 100 psig and (b) 200 psig

80 °C. Figure 7 shows variation of permeability reduction with time at different temperatures. It also shows that at higher temperatures the permeability declines more rapidly. This is because the rate of $CaSO_4$ and $SrSO_4$ precipitations increases with temperature. The increase in temperature also causes a raise in super-saturation, because the solubility of $CaSO_4$ and $SrSO_4$ decrease with temperature. This must have led to an increase of rate of precipitation and consequently a faster permeability decline. Figure 8 shows the variation of permeability reduction with time at different temperatures. It also shows the effect of temperature on permeability reduction as temperature rises, the rate of nucleation and crystal growth and plugging were decreased. The permeability decline is less rapid at higher temperature, since the rate of $BaSO_4$ precipitation decrease with temperature. This is because the solubility of $BaSO_4$ increases with temperature.

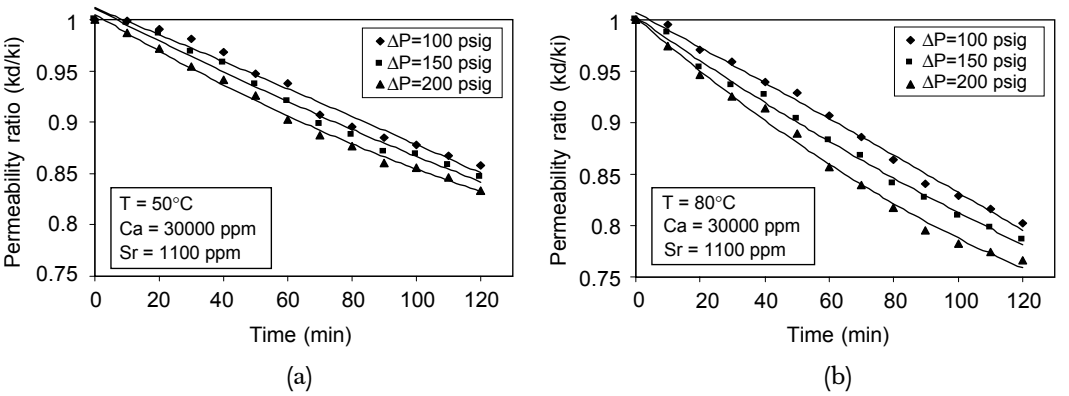

Figure 9 Variation of permeability ratio *vs.* time at various differential pressures (a) 50 °C and (b) 80 °C

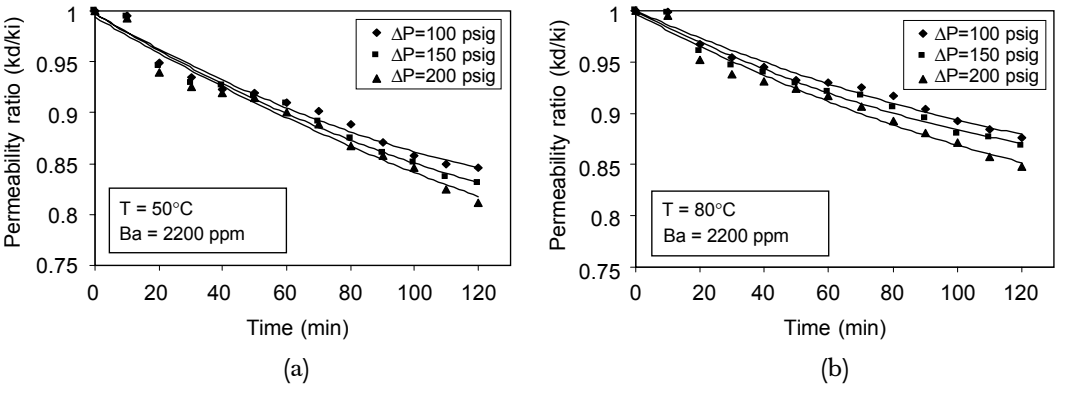

Figure 10 Variation of permeability ratio *vs.* time at various differential pressures (a) 50 °C and (b) 80 °C

3.2.4 Effect of Differential Pressure

To investigate the effect of differential pressure on flow rate and permeability reduction a number of tests were carried out. In these experiments, the concentration of brine and temperature were kept constant and differential pressure varied from 100 to 200 psig. The variation of permeability reduction with time at different differential pressures is show in Figures 9 and 10. From these figures, the permeability decline of porous medium is evident, even at such low differential pressures. The results illustrate that at low differential pressure, scale formation has already as significant effect on the permeability decline. As, the differential pressure was increased, the rate of permeability decline becomes more rapid. Moreover, at higher differential pressure more sulfate ions will pass through the porous medium in a given interval of time. The super-saturation at the porous medium will therefore increase the rate of

precipitation. This increased precipitation rate will produce a larger permeability decline.

3.2.5 Effect of Concentration

A number of tests were carried out to study the effect of brine concentration on permeability reduction. These tests were performed at differential pressure from 100 to 200 psig and temperatures of 50 and 80 °C with two different brine concentrations (see Table 2). Figures 11 and 12 show the variation in permeability decline with time for different concentrations of calcium, strontium and barium ions. When the concentration of brine (i.e. super-saturation) is increasing, plugging and hence permeability loss occurs more rapidly. The permeability decline due to high con-centration of calcium, strontium, and barium is greater than for normal

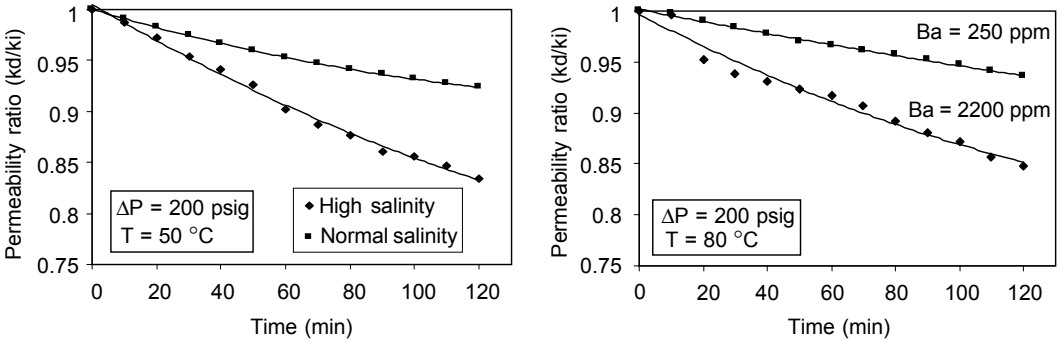

Figure 11 Variation of permeability ratio *vs.* time at various concentrations (a) 50 °C and (b) 80 °C and 200 psig

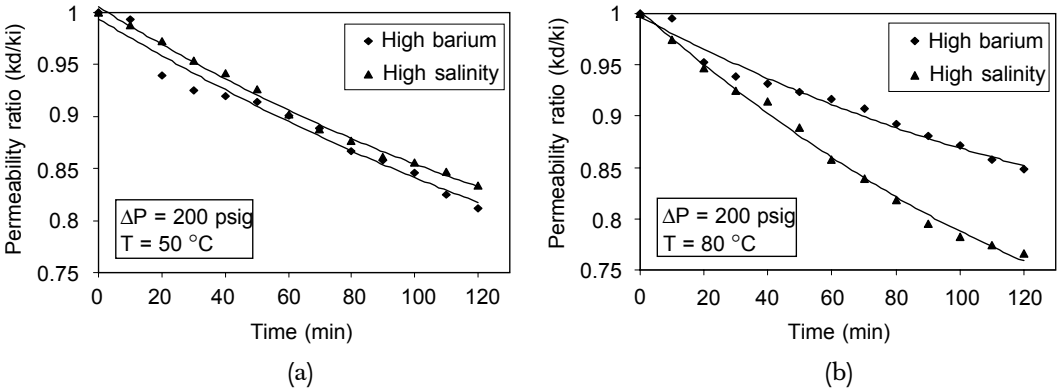

Figure 12 Variation of permeability ratio *vs.* time at various concentrations (a) 50 °C and (b) 80 °C and 200 psig

con-centration of calcium, strontium, and barium ions, for given experimental conditions.

3.2.6 Scanning Electron Microscopic Analysis

The scaled core samples were examined by scanning electron microscopy (SEM) to observe the particle size and morphology of the precipitates. The formations of $CaSO_4$, $SrSO_4$, and $BaSO_4$ during the flow of injection and formation waters in the porous media were observed by SEM micrographs. Figures 13 and 14 show the SEM image of the $CaSO_4$, $SrSO_4$, and $BaSO_4$ scaling crystals in rock pores precipitated from mixed seawater with formation water inside the cores. Comparison of $BaSO_4$ with $CaSO_4$ and $SrSO_4$ formed in the porous media did not show significant difference in crystal external morphology. The difference line in the irregularity of the crystals formed in the rock pores and the crystal size variations from one location to another in a core. The average size of $BaSO_4$ crystals precipitated from mixed brines was

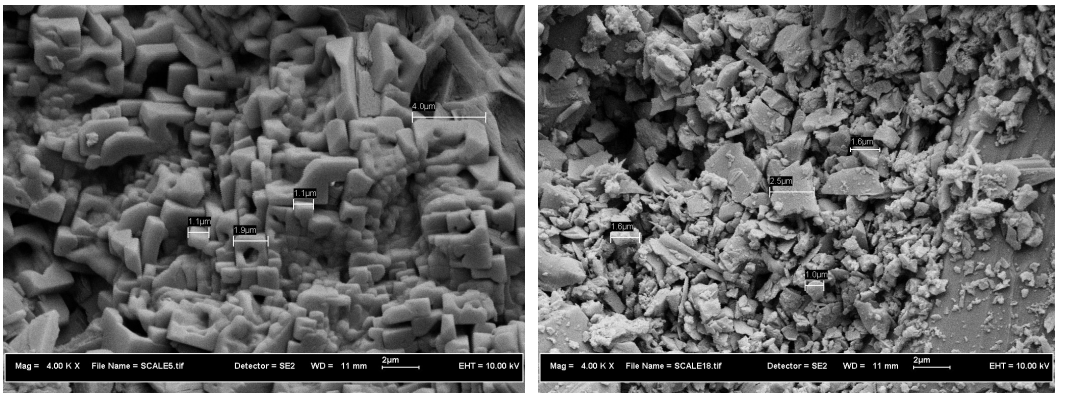

Figure 13 SEM image of $CaSO_4$ and $SrSO_4$scales in sandstone cores

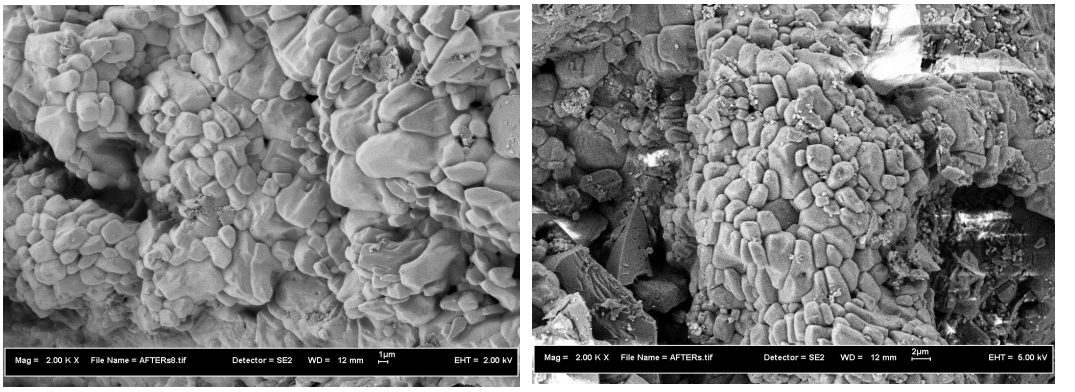

Figure 14 SEM image of $BaSO_4$ scale in sandstone cores

about 2.5 μm larger than the average size of $CaSO_4$ and $SrSO_4$ crystals was about 1.8 μm.

In all core tests, the abundance of scale reduced significantly from the front of the core to the rear indicating that scale formation in porous media was rapid with the observation that the flow rate decreased soon after two incompatible waters were mixed into a core. The observations of scaling sites from previous tests [5] were confirmed by this test results.

In general, Figures 13 and 14 indicate that the front sections of a core suffered considerable greater scaling damage. The reason the scaling decreased downstream of a core is clear most of the scaling ions had deposited within the front sections as soon as they were mixed and left few ions to precipitate from the flow stream in the rear sections. Figure 15 shows a SEM image of an unscaled core samples.

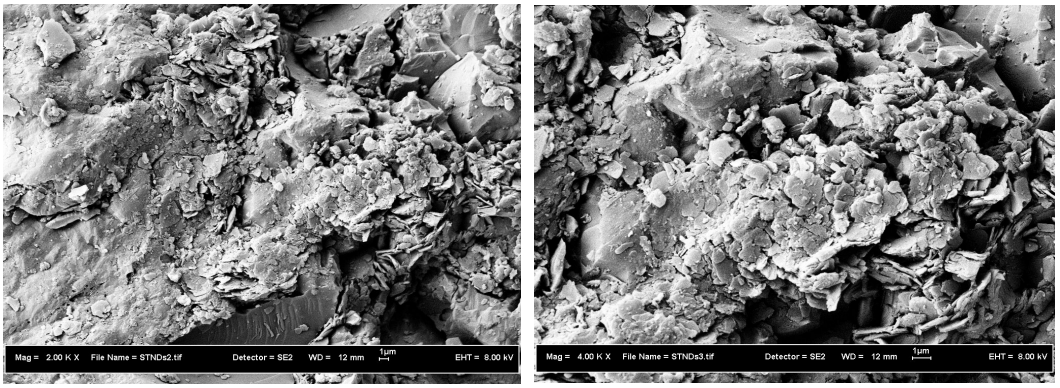

Figure 15 SEM image of an unscaled sandstone core

5.0 CONCLUSIONS

The experimental results confirm the general trend in solubility dependencies for common oil field scales, determined at various temperatures. A temperature rise from 40 to 90 °C causes an incre-ase in $BaSO_4$ solubility and a decrease of $CaSO_4$ and $SrSO_4$ solubilities.

Permeability decline caused by $CaSO_4$, $SrSO_4$ and $BaSO_4$ scale formation in the porous media ranged from 4% to 23% of the initial permeability, depending on brine composition, initial permeability, temperature, differential pressure, and brine injection period.

The worst permeability loss occurred in the porous media from 15% to 23% of the initial permeability at temperature (80 °C) and differential pressure (200 psig) for $CaSO_4$ and $SrSO_4$ experiments and from 9% to 19% of the initial permeability at temperature (50 °C) and differential pressure (200 psig) for $BaSO_4$ experiments.

The pattern of permeability decline in a porous medium due to scaling injection was characterized by a concave curve with a steep initial decline which gradually

slowed down to a lower. The initial steepness of these curves generally decreased with increasing distance from the point of mixing of the incompatible brines. The concave shape of the permeability-time curves was common to the majority of the porous medium flow tests.

Several factors influencing scale formation had been examined. Increasing temperature, concentration of brine (i.e. super-saturation) and differential pressure had a detrimental effect on the permeability reduction.

The formation of $CaSO_4$ and $SrSO_4$ during flow of injection and formation waters in porous media have been proved by Scanning Electron Microscopy (SEM) micrographs show $CaSO_4$ and $SrSO_4$ crystals formation in porous space.

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